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Clean Energy

September 22, 2014

Via E-mail

Michael S. Waugh
Chief, Transportation Fuels Branch
1001 I Street
California Air Resources Board
Sacramento, CA 95814

RE: Clean Energy's Comments on ARB's Low Carbon Fuel Standard Reconsideration –CA-GREET Model Update Proposal at the August 22, 2014.

Dear Mr. Waugh and Members of the Air Resources Board Staff:

Clean Energy would like to thank the Air Resources Board (ARB) staff for allowing us to comment on staff's proposed changes to the current California-GREET Model 1.8b. The proposed update will change several carbon intensity (CI) pathways that include baseline fuels, both natural gas and renewable natural gas, biodiesel, renewable diesel, and ethanol. These changes will include more pathways and feedstock's, life cycle inventory data updates, updated emission factors, updated efficiency factors, and updated electrical energy generation mixes.

Clean Energy is North America's leading fuel provider of both conventional and renewable natural gas for transportation with over 550 stations operating in 43 states across the country. The company has been a longtime supporter of California's climate change goals under AB 32 and ARB's implementation of the nation's first Low Carbon Fuel Standard (LCFS).

Unfortunately, a representative from Clean Energy was not able to attend the August 22, 2014 Workshop in person and our plans to participate by webcast were disrupted when the company's virus software blocked our ability to connect with ARB's website. We would therefore like to confirm a few things with ARB staff regarding the process moving forward. First, it is our understanding that the August 22, 2014 workshop was intended as a preliminary presentation of potential changes to the CA-GREET 1.8b model and we would like you to confirm this understanding. We have also been told that the work on a final CA-GREET 2.0 model is ongoing and will be a lengthy process. Can ARB please provide an estimated timeline of the process to update the CA-GREET Model from start to finish so that we may allocate the necessary resources required to support ARB in reaching an accurate analysis on CI pathways for compressed natural gas (CNG), liquefied natural gas (LNG) and renewable natural gas (RNG)? We have learned through other stakeholders that ARB is planning to bring this item to

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the Board as soon as January 2015. We hope that this is not the case as this would be a very rushed schedule and would exclude numerous studies expected to be released next year on upstream methane emissions.

Finally, the following comments are intended as a preliminary response to the information presented by ARB staff to date. We would like to formally request an in-person meeting with ARB staff assigned to updating the CA-GREET Model 2.0 and have the ability to conference in other interested Industry stakeholders that would also like to participate. We would like to thank ARB staff in advance for their willingness to accommodate this request.

ARB Must Pursue a Deliberative Approach to Revisions of CI Values to the CA GREET Model to Preserve the Credibility of and Confidence in California's Low Carbon Fuel Standard

ARB staff's presentation at the August 22, 2014 Workshop proposes to drastically alter the carbon intensity of several low to ultra-low carbon fuels. In some cases, the changes would increase CI values by nearly 300 percent. The information supporting these changes, however, has not been made available to those impacted and, therefore, a full vetting of the issues related to these revisions cannot be performed. Clean Energy is very concerned about the uncertainty this creates for businesses and industries impacted by the LCFS rules. Specifically, these proposed updates would have significant impacts not only on investments that have been made in good faith reliance on the regulation, but on the compliance plans that have incorporated these fuels and pathways, and on the general confidence of the market to rely on the LCFS regulation.

Further, we are also concerned about the broader impact this could have on the impression that other important stakeholders will have with respect to the benefits of using natural gas. What if ARB gets it wrong by failing to perform a deliberative and thoughtful review of upstream methane emissions and erroneously rules out an option that could have otherwise contributed significantly to warding off climate change? What if the remaining technologies fail to deliver operational product in the heavy-duty space as they have in the past because technology is not ready?[1] What will ARB's strategy be in reducing greenhouse gases for heavy-duty vehicle applications when we know that largest source of pollution in the South Coast Air Basin and the Natural Gas Vehicle Industry's growth stalls because ARB posted an incorrect leakage rate and failed to account for federal and state regulations that are or being prepared to address upstream emissions?

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We therefore request that ARB provide full transparency on their justifications (i.e., data, assumptions, analysis) to alter the GREET model designed to capture upstream methane emissions. Without this kind of transparency, it is impossible to comment on the validity of the new values. Further, the science of the lifecycle analysis pertaining to methane leakage rates continues to evolve and is not without controversy. Even ARB staff's Technology Assessment of Transportation Fuels presentation on September 3, 2014 admits in numerous locations that there is no standardization of methodologies to estimate leakage rates which makes comparative reviews difficult (i.e., "one can get more than 3 different rates with the same emissions data depending on your methodology").[2] Further, during the Technology Assessment of Fuels Workshop, it is troublesome to see ARB staff presenting citations of studies that are known to have been thoroughly debunked like Howarth[3], highlighting a 17% leakage rate number from NOAA that is widely known to be associated with oil production[4], or to focus on Brandt, et al.,[5] when the author is even the first to say that his findings were based on "top down" measurements where you would capture both biogenic and anthropogenic sources.

We have heard that ARB staff intends to provide their findings for board approval by January 2015. Given the tremendous uncertainty surrounding the science of upstream methane emissions, we hope this rumor is a complete misunderstanding and that ARB is committed to providing a full deliberative process that allows for information exchange, adequate time for all sides to comment, and come to agreement.

More Studies are Underway and Federal and State Legislation and Regulation is Moving Ahead

At the September 3, 2014 Workshop, ARB staff points out that more than twenty ongoing studies related to methane leakage are taking place today to better understand the issue. These studies include four studies by the California Energy Commission (CEC), sixteen modules by EDF, and a national Gas Technology Institute (GTI) study that ARB is supplementing with California specific measurements.[6] In other words, we should have better data soon to review, analyze and compare to get to a better methane leakage rate.

As this critical research is taking place, regulators and legislators are taking corrective action to reduce upstream methane emissions. Here in California, the Legislature just passed SB 1371 (Leno) which will open a Public Utilities Commission proceeding to adopt rules and procedures that minimize natural gas leaks.[7] In 2012, the EPA adopted a Green Completions program that by its own description, "generally requires owners/operators to use reduced emissions completions, also known as "RECs" or "green completions," to reduce VOC emissions from well completions. To achieve these VOC reductions, owners and/or operators may use RECs or completion combustion devices, such as flaring, until January 1, 2015; as of January 1, 2015, owners and/or operators must use RECs and a completion combustion device."

Green completion essentially requires natural gas companies to capture the gas at the well head immediately after well completion instead of releasing it into the atmosphere or flaring it off. EPA Administrator Gina McCarthy's comments on the program states that "The action taken today is expected to yield nearly a 95 percent reduction in smog-forming volatile organic compounds emitted from more than 13,000 hydraulically fractured gas wells each year."

From this information, one must conclude that regulation is in place or taking shape to further reduce or eliminate upstream methane leakage and additional, pertinent information is being collected now that we should review prior to changing the CI for natural gas. ARB should not act precipitously by adopting changes based on incomplete data.

To Spur the Conversation, Clean Energy has the following Observations Questions for ARB Staff on the Proposed CA-GREET 2.0 Model

First and foremost, Clean Energy needs to understand the specifics as to why the 2.0 model differs from the 1.8b model.

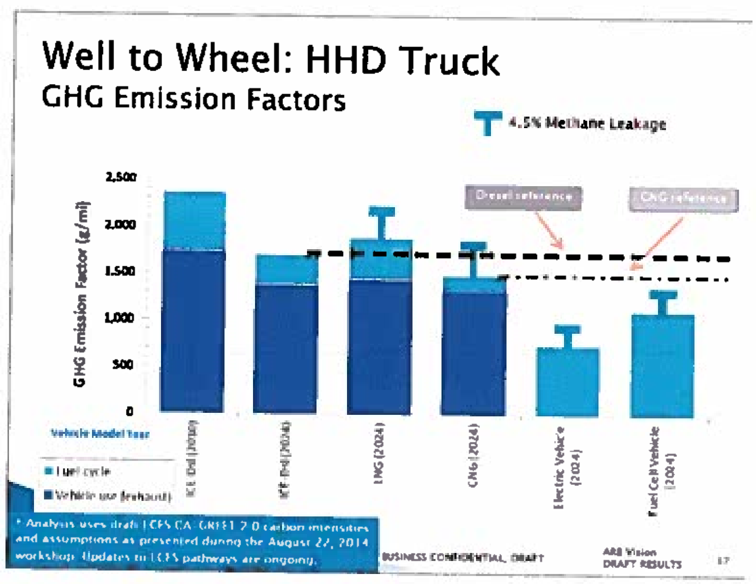
- Many existing pathways (e.g. specific pathways for a number of LNG plants) have been determined by specific process efficiencies (e.g. kwh/gallon, etc.) ;
- CI for these pathways will not necessarily change unless overarching assumptions have been changed by Argonne;
- The general public and Industry needs to fully understand what adjustments Argonne made to the model and then determine if those revisions will change the CI that has already been determined for the specific LNG plants;
- Under the LCFS, applicants have to submit calculations for individual LNG plants. The CI is totally dependent upon the process technology which can differ for each plant. It is unlikely that Argonne has/will adopt one generic LNG CI for LNG;

- Looking at all of the individual pathways that have been submitted for each fuel type under the LCFS – it is clear that one size does not fit all for pathways;
- CARB has also noted that even for petroleum refineries – the CI for individual plants differs widely. For petroleum though, CARB adopted an "average" CI for petroleum based fuels. Such an average is not appropriate for other fuels that are produced on a much smaller scale than petroleum with potential radically different technology for each plant for the same fuel;
- In ARB's August 22, 2014 presentation, the CI for LNG is noted as 83.13 gm/MJ. This CI is for an 80% efficient LNG production plant in California. ARB also notes that the CI for a 90% efficient LNG plant is 72.38 gm/MJ. It should be noted that all the submittals for LNG pathways since the beginning of the LCFS program are for production plants with greater than 90% efficiency. ARB's presentation thus totally misrepresents the carbon intensity of LNG and should be corrected.
- LCFS is about defining the carbon intensity of fuels
    - The primary purpose of the LCFS is to achieve lower carbon intensity for fuels in the marketplace.
    - More recent CARB documents switch from discussions of the carbon intensity of fuels to the GHG impacts in grams per mile of GHG emissions.
    - While this is certainly a natural progression of thought – it should be considered as a separate technical discussion.
    - If for instance, petroleum CI is reduced by the program by the 10% by 2020 designed in the program, that fuel can be legally burned in a vehicle that has a 10 mpg fuel economy. The GHG emissions from that 10 mpg vehicle will look miserable in comparison to GHGs from vehicles that achieve 40-50 mpg.
    - Modifications to the LCFS should confine themselves to determining the CI of fuels and not be modified to include end use emissions from vehicles.

Updated Leakage Rates for Natural Gas Impacts More Transportation Fuels than Natural Gas Vehicles (NGVs). ARB Must Apply Upstream Methane Emissions Across the Entire Transportation Sector to Maintain "Fuel Neutrality".

While Clean Energy questions the accuracy of upstream fugitive methane emission leakage rates given the current science and conflicting methodologies, the United States has an abundant supply of clean, cheap and domestic natural gas[8] that is used by other alternative fuels at some point in their production cycles: biodiesel, electricity, ethanol, gas-to-liquids, hydrogen, methanol, propane, etc.[9] Fully acknowledging that we don't necessarily agree with the proposed warming impacts stated by ARB in their proposed presentation and noting that some of the fuels that are noted may not be used in California to generate LCFS credits but two transportation fuels that rely heavily upon natural gas in their fuel pathways are clearly engaged in the state's LCFS program are oddly not included in the ARB's August 22, 2014 presentation: electricity and hydrogen.

ARB's September 3, 2014 Technology Assessment presentation on Transportation Fuels does, however, highlight the fact that upstream methane leakage could have a similar impact on the carbon performance of both electric and hydrogen vehicle technology begging the question as to why the proposed CA-GREET Model update excludes re-evaluating the carbon intensity numbers for all vehicle strategies that use natural gas?



Since the shutdown of Southern California Edison's 2,150-megawatt (MW) nuclear facility at San Onofre, California now draws more than sixty percent of its power from natural gas.[10] Thus, there is no doubt that upstream methane emissions will have a direct impact upon electric vehicles (EV) and plug-in electric vehicles (PHEV) carbon performance in California. As for hydrogen fuel cell vehicles (FCEV), bulk hydrogen is usually produced by the steam reforming of methane or natural gas.[11] It is true that SB 1505 requires 33.3% of hydrogen be produced using renewables but the other 66.6% is likely to come from the use of natural gas due based on cost-effectiveness.[12] Thus, there is little doubt that the CI pathways for hydrogen will also be significantly impacted by upstream methane emissions.

Of course, other fuels like propane can be derived from natural gas before they become a transportation fuel making the case that all transportation fuels must be reviewed and have their CI values adjusted accordingly if natural gas is used in a fuel's pathway. Otherwise, ARB would appear to be picking winners and distancing them from their "fuel neutral" position. Clean Energy does not believe that this is the intent of ARB staff and would like a commitment from ARB staff to perform a thorough review of every fuel pathway that uses natural gas at some point in their lifecycle and apply an upstream methane emission factor to accurately account for that impact. Furthermore, no changes to any CI value should occur until ARB completes a full analysis of all fuels and can adjust CI numbers for all fuels, not just natural gas. Failure to do so would create both an un-level playing field amongst low carbon fuel options and would cast a perception of bias upon the regulatory agency on a rule that is already hotly contested by opposition: the LCFS.

ARB Must Ensure that the Methane Leakage Data Used to Calculate Upstream Emissions Losses is Accurate and Representative of the Industry's Performance. ARB Should Not Rush Ahead of the Science and Repeat EPA's Misstep in 2011.

In 2012, the Environmental Defense Fund (EDF), a major U.S. environmental organization, published a study claiming that natural gas vehicles (NGVs) have greater short-term climate change impact than either gasoline or diesel vehicles. The EDF study alleged that the fuel cycle greenhouse gases emissions from natural gas production, i.e. those emissions that take place before the natural gas ever makes it in to a vehicle, have more near-term impact on global climate change than the fuel cycle emissions for diesel or gasoline. This study's conclusions relied on flawed and incomplete data from the United States Environmental Protection Agency (EPA). Although EDF itself acknowledged flaws in EPA's data and has since launched 16 independent projects to gather improved data on methane loss, this study and others similar to it may unfairly impact how the general public and regulators perceive NGVs.

The basis of EDF's report comes from changes in the way that EPA estimated the amount of natural gas that escapes into the atmosphere during the exploration, production, storage and transport of natural gas. Using a very limited set of preliminary data gathered from a small number of gas producers and wells, EPA precipitously increased its assumptions about the amount of methane that is lost during the natural gas field production. The vast majority of this increase was attributed to revised estimates from two elements of natural gas production: how natural gas wells undergo "cleanups," and emissions from new production processes in the completion and work overs of natural gas wells. Unfortunately, the revised estimates are not supported by robust analytical justification nor do they utilize a complete set of data points from across the gas production industry.

There are a broad set of problems associated with the data that EPA used to justify this change, and there are reports that even EPA's own scientists have acknowledged that there are "issues" associated with the data they have used to modify the GHG inventory. The natural gas industry has been both frustrated and disappointed by the EPA's approach to this issue, noting that the revised emission estimates are based on "fundamentally flawed data and analysis." Some of the main issues include:

EPA's methodologies were extrapolated from a handful of data points that were never intended to represent industry-wide practices or estimates of fugitive methane emissions. EPA's data set and supporting methodologies were developed from case studies from just a few producers and do not represent actual conditions or in-field industry-wide emissions; EPA's calculations vastly underestimate the use of latest "green completion" technology in capturing fugitive gas at well sites. These technologies are widely used throughout the industry because this methane is a valuable commodity. Under the revised EPA estimates, industry would be forgoing over $780 million of annual revenue due to lost natural gas; EPA's underlying methodologies and assumptions are incomplete and based on extremely limited data points, leading to inflated amounts of methane lost during completions and recompletions and an overestimation of the number of recompletions of a well.

Although there was significant dissent from the natural gas industry regarding the data set and change in EPA's fugitive methane assumptions, the agency formalized its modifications in April 2011 by forwarding these new figures to the Intergovernmental Panel on Climate Change (IPCC). The IPCC was established by the United Nations Environment Program (UNEP) and the World Meteorological Organization (WMO) to provide a clear scientific view on the current state of climate change knowledge and is responsible for keeping the inventory of the planet's GHG emissions. By submitting the disputed fugitive methane figures to IPCC as a part of its

U.S. inventory of GHG emissions, the EPA codified its mistakes and altered official calculations of the climate change potential of NGVs.

It is worth noting that EPA since 2011 has issued several new annual GHG Inventory Reports and they confirm that NG emissions are going down and not as high as the previous reports suggested. The AGA analysis includes the following findings[13]:

- Methane emissions from the natural gas value chain, which includes field production, processing, transmissions and storage, and distribution, result in an effective 1.3 percent emissions rate of produced natural gas.
- Natural gas utility distribution systems methane emissions amount to an emissions rate of 0.24 percent of produced natural gas in 2012.
- Natural gas system methane emissions were 130 million metric tons of carbon dioxide equivalents (MMTe) in 2012, a decline of 17 percent from 1990 levels and 15 percent below 2005.
- Distribution system methane emissions were 26 MMTe in 2012 and have shrunk 22 percent between 1990 and 2012, even as the industry added 600,000 miles of total pipe (service and main lines) to serve 17.5 million more customers, an increase of 32 percent in both cases.

- Nearly 90 percent of the historical drops in methane emissions from distribution systems since 1990 are a direct result of pipeline upgrades to modern plastic and protected steel.

ARB should not repeat the same mistakes that EPA made in 2011 by submitting and endorsing a set of findings that was not representative, used incomplete methodologies and assumptions, or accurate. ARB Technology Assessment of Transportation Fuels on September 3, 2014 admits in numerous locations that there is no standardization of methodologies to estimate leakage rates which makes comparative reviews difficult (i.e., "one can get more than 3 different rates with the same emissions data depending on your methodology").[14]

Landfill Gas Extraction and Processing Adjustments Appear to Be Based on Inapplicable Research

There is good reason to question the 2% leakage adder being attributed by the ARB in its proposed changes to Renewable-CNG and Renewable-LNG from landfill biogas feedstock. The ARB staff should investigate further the sources used as the basis for this proposed leakage adder and consider its relevance to the RNG production processes that exist at North American landfills.

We understand that the Argonne National Laboratory (ANL) Waste-to-Wheel study[15] is a key source for this number. The study says:

CH4 vented or leaked from equipment during AD, NG production or upgrading is a major source of GHG emissions. On the basis of several Swedish reports, Börjesson and Berglund (2006) estimate that 2% of the biogas produced is vented or leaked during these stages. This value is significantly larger than the 0.15% emission rate for conventional NG upgrading facilities, but could be attributed to differences in scale (Burnham et al., 2011). Therefore, this study assumes that 2% of the produced renewable gas is leaked. As indicated by Börjesson and Berglund (2006), more research on CH4 emissions from anaerobic digesters and small-scale NG processing facilities is warranted for a more comprehensive understanding of biogas-based pathways.[16]

Upon review, we see that the 2006 Börjesson[17] and Berglund[18] studies relied upon to reach a 2% "vented or leaked" assumption are from at least nine-year-old studies of anaerobic digestion facilities in Sweden - and not of landfill gas systems, or systems in the U.S.

Furthermore, and most critically, based on the 2013 Swedish Gas Technology Report (SGR)[19], it appears that ANL arrives at a 2% methane loss from RNG processing plants ***that do not employ a thermal oxidizer or combust the waste gas produced.***

Methane capture on farms is unregulated. As such, most unused (excess, waste or "tail") gas from these projects is vented instead of destroyed. However, as U.S. landfill gas systems are heavily regulated for emissions, all U.S. landfill gas-to-energy facilities utilize a thermal oxidizer or flare to combust and destroy unused waste gas. The 2% leakage, therefore, that might occur at a Swedish digester based biogas project without a waste gas combustion device is entirely irrelevant to the leakage rate at a U.S. landfill gas-to-energy RNG production facility.

We do not question ANL, Börjesson, Berglund, or SGR as a credible sources, but we do question the relevance of and weight given to these studies and strongly suggest that it is inappropriate to apply a 2% methane leakage rate rooted in a different production and processing system (biogas AD) from a different country (Sweden) with different regulations, to landfill gas operations in the United States. We continue to review these studies, but our early analysis leads us to conclude that the calculation application is not appropriate.

We are not aware of any data that supports the idea that processing of RNG at a landfill will lead to greater methane emissions compared to combusting the same methane in a flare or thermal oxidizer – both of which are very efficient combustion devices.

Moreover, and perhaps most critical, the ARB must consider the fact that RNG producers frequently invest in methane capture at landfills that greatly exceeds the rate of methane capture that would occur in the absence of the project. In fact, RNG projects at landfills typically have a far greater density of wells with more tightly controlled vacuum applied to those wells, than other types of energy projects at landfills. Many of our member companies have invested millions of dollars in wells and gas collection infrastructure at their projects to capture methane from sections of the landfill that have not yet triggered the gas collection requirements of the U.S. EPA New Source Performance Standards (NSPS). The assumption that all of the methane captured at a landfill and processed into RNG would have been destroyed in the flare absent the RNG production process is inaccurate.

Under federal regulations, a major section of a landfill can be operated without a landfill gas collection system for as up to five years from the date that waste is first deposited at the landfill before installation of a gas collection system is required. In the absence of an RNG production project or facility, significant quantities of the methane produced at the landfill will vent into the atmosphere from the areas of the landfill that are not yet regulated. The production and sale of RNG provides the economic incentive to capture as many molecules of methane from the landfill as possible, and also provides the revenue stream necessary to pay for the additional gas collection system improvements needed to make increased methane capture possible.

In fact, a third-party carbon credit verification firm that reviewed landfill gas collection at our McCommas Bluff RNG production plant concluded that, through installation of wells and gas collection equipment in "unregulated" portions of the landfill our project had voluntarily reduced GHG emissions from the landfill by over 1.2 million tons of CO2e from 2009 through 2013 (see attached Exhibit A). This is 1.2 million tons of GHG emissions that were prevented by exceeding the regulatory baseline for gas collection and destruction at the landfill. These reductions are nowhere taken into account in the Argonne data. If the ARB is going to adjust the RNG from Landfill Gas Pathway, this "early well installation" and methane capture and destruction must also be taken into account in determining the CI of the bio methane.

Conclusion

ARB has a responsibility not only to the Industries that it impacts but also to the market participants and supporters that have spent countless hours supporting the LCFS to get carbon intensities associated with fuel strategies right, to pursue a deliberative process that is inclusive of the best available and reasonably anticipated data, and to provide the transparency of ARB assumptions, analysis, and judgments so that the agency can receive qualified and credible feedback. Anything short of a transparent, inclusive and deliberative process will harm the LCFS market and the integrity of the program.

Sincerely,

Todd R. Campbell
Vice President Public Policy & Regulatory Affairs

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[1] See Zero Emission Bus requirement of ARB's Transit Bus Rule as adopted in 2011: 15% ZEB purchase requirement in 2008 not implemented.
[2] Slide 52 of ARB's Technology Assessment of Transportation Fuels, September 3, 2014.
[3] Slide 54 of ARB's Technology Assessment of Transportation Fuels, September 3, 2014.
[4] Slide 67 of ARB's Technology Assessment of Transportation Fuels, September 3, 2014.
[5] Slide 55 of ARB's Technology Assessment of Transportation Fuels, September 3, 2014.
[6] Slide 69 of ARB's Technology Assessment of Transportation Fuels, September 3, 2014.
[7] Senate Bill 1371 (Leno), Enrolled 8/29/14. Senate Floor Analysis, 8/27/14.
[8] http://anga.us/why-natural-gas/abundant
[9] This is more of an illustrative list of fuels that can be produced with the help of natural gas. It is not an exhaustive list and should not be viewed as such.
[10] http://www.reuters.com/article/2013/06/09/us-utilities-sanonofre-natgas-analysis-idUSBRE95802620130609
[11] http://en.wikipedia.org/wiki/Hydrogen_production
[12] http://energy.gov/sites/prod/files/2014/03/f12/renewable_hydrogen_workshop_nov16_achtelik.pdf

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[13] http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/UpdatingtheFactsEmissionsfromNaturalGasSystems.aspx

[14] Slide 52 of ARB's Technology Assessment of Transportation Fuels, September 3, 2014.
[15] Han, Mintz & Wang. *Waste-to-Wheel Analysis of Anaerobic-Digestion-Based Renewable Natural Gas Pathways with the GREET Model*, Argon National Laboratory, Center for Transportation Research, Energy Systems Division, September 2011. (ANL Waste-to-Wheels).
[16] ANL Waste-to-Wheels, at 15-16.
[17] Börjesson, P., Berglund, M., 2006. Environmental systems analysis of biogas systems—Part I: Fuel-cycle emissions. Biomass and Bioenergy 30, 469–485.
[18] Berglund, M., Börjesson, P., 2006. Assessment of energy performance in the life-cycle of biogas production. Biomass and Bioenergy 30, 254–266.
[19] Bauer, F., Hulteberg, C., Persson, T., Tamm, D., 2013. Swedish Gas Technology Centre Rapport. Description of the available upgrading technologies. Membrane separation, 28-31.